POTENTIAL MARKET PENETRATION OF IGCC IN THE NORTH EAST UNITED STATES

(PHASE I)

TOPICAL REPORT

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Disclaimer

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EXECUTIVE SUMMARY

The objective of this study is to provide The National Energy Technology Laboratory (NETL) with information to aid in the development of a strategic marketing plan for commercial domestic deployment of IGCC technologies for coal-based power generation. Major drivers of the electric market examined in the study are technology development, environmental issues, and demand growth. This phase of the study examines IGCC market penetration potential for baseload power generation in the Northeast U.S., an important market area for IGCC because of the existing coal generation infrastructure and its proximity to coal producing regions. The modified CONSOL Regional Compliance Model (RCM)[1] model was used to evaluate the options for the Northeast region. IGCC was evaluated both as a replacement option for existing power plants and as a new capacity option to satisfy load growth requirements. Using the bus bar cost of electricity as the deciding factor, the RCM considers generation technologies and fuel options to supply power taking into account load projections, emission costs, fuel price projections, plant performance, and capital and operating cost estimates. The emissions costs, in the form of a tax or allowance price (or another equivalent mechanism), consider CO_2, SO_2, and NO_x emissions. All of the options were evaluated at a fixed capacity factor of 80 percent and the mix of technologies giving the lowest cost of electricity was chosen. Two parameters were investigated in this study. These were the price of natural gas and the imposition of a carbon tax. Natural gas price was varied from a low escalation rate of 0.54 percent per year to a high rate of 4.5 percent per year and the carbon tax was varied from $0/tonne to $100/tonne of carbon.

The results of the IGCC market penetration study show that the most critical factor affecting deployment of IGCC to the year 2010 is the level of technology advancement that can be achieved. Without improvements in cost and performance compared to the current state of development, **no** IGCC market penetration is expected in either the replacement unit or new capacity market segments regardless of market conditions. This analysis assumes that the current IGCC heat rate and capital cost of the air-blown and oxygen-blown systems are 8,106 Btu/kWh and $1,392/kW, and 8,522 Btu/kWh and $1,241/kW, respectively. Although site- and market condition-specific, IGCC power costs from current technology are greater than other new plant, coal-fired technology options.

Coal-fired technology options installed in preference to current technology IGCC are subcritical pulverized-coal (PC) units at lower carbon taxes and higher efficiency, and advanced pressurized fluidized bed combustor (PFBC) units at higher carbon taxes. Advanced, natural gas-combined cycle (NGCC) plants dominate the replacement plant and new capacity market segments at low gas price escalation rate and high carbon tax market conditions. Advanced NGCC market penetration declines at high gas price escalation rates and low carbon tax market conditions. A significant number of existing coal-fired plants purchase emission allowances or retrofit emission control equipment as a compliance strategy at lower carbon taxes. Increasing the carbon tax from $50 to $100/tonne C significantly changes the compliance strategy at existing units toward plant replacement with higher efficiency coal- and natural gas fired technologies.

Performance and cost improvements from the current level of development to an "advanced" level will allow IGCC to effectively compete with advanced NGCC and with other coal-fired technologies in the power market. Advanced technology IGCC has significant market penetration under most market conditions. The advanced technology heat rate and capital cost assumed in this study are 6,870 Btu/kWh and $961/kW respectively, based on recent estimates by Parsons[3]. This represents a 16-20% heat rate improvement and a 23-30% capital cost reduction from current IGCC technologies. At this performance/cost level, IGCC technology is **superior** to all other coal-fired technologies examined.

Over the range of market conditions examined, the maximum market penetration for advanced IGCC occurs at the highest gas price escalation and the highest carbon tax. Under these market conditions, total IGCC penetration in the Northeast would be 71 plants with a total dispatchable capacity (net capacity based on availability) of 25 GW. With these conditions, IGCC dominates the power market over advanced NGCC and only demand and other compliance options available at existing plants limit the market penetration. The high gas price escalation, which favors coal, more than offsets the carbon tax, which favors gas. Forty six per cent of the 110 existing coal-fired units, or 33 units, are replaced and repowered with IGCC. For the majority of existing coal-fired units, emission allowance purchases or emission control retrofits are still the most cost-effective compliance strategies. These compliance strategies avoid the capital charges associated with new plant construction.

The major conclusion from this phase of the study is that if IGCC is to be a future player in the U.S. power market, it is imperative to continue development of IGCC technology to reduce capital costs to about $1000/kW and improve heat rates to less than 7,000 Btu/kWh. If these targets can be achieved, IGCC can then effectively compete with other coal-fired technologies and, more importantly, with NGCC technology. IGCC will be the **coal-fired technology of choice** if the performance and cost estimates used in the study are achieved.

INTRODUCTION

Mitretek Systems of McLean, Virginia and CONSOL Inc. Research and Development of South Park, Pennsylvania are conducting a market penetration study of Integrated Gasification Combined Cycle (IGCC) technology as a means of producing domestic electric power from coal in the year 2010. The National Energy Technology Laboratory (NETL) of the U. S. Department of Energy (DOE) funded the study.

The objective of this study is to provide NETL with information to aid in the development of a strategic marketing plan for commercial domestic deployment of IGCC technologies for coal-based power generation. Major drivers of the electric market examined in the study are technology development, environmental issues, and demand growth.

This phase of the study examines IGCC market penetration potential for baseload power generation in the Northeast U.S., an important market area for IGCC because of the existing coal generation infrastructure and its proximity to coal producing regions. Three utility power pools supply most of the power for this region. They are the Pennsylvania, New Jersey, Maryland Power Pool (PJM), the New York Power Pool (NYPP), and the New England Power Exchange (NEPEX). There are 110 coal-fired power plants in this region with 14 being in NEPEX, 30 in the NYPP pool and 66 in the PJM pool. Each of these plants has its own specific firing mode, performance, fuel specifications, fuel costs, emissions, and emission controls. Unit capacity varies from small plants of 25 MW to large plants of 950 MW. There are considerable variations in heat rate of these plants from a low of 8,900 Btu/kWh to a high of 15,000 Btu/kWh. The plants have a wide variety of SOx and NOx controls.

The CONSOL Regional Compliance Model (RCM)[1] was configured to evaluate the power market in the northeast region of the U.S. IGCC was evaluated both as a replacement option for existing power plants and as a new capacity option to satisfy load growth requirements. Using the bus bar cost of electricity as the deciding factor, the RCM considers generation technologies and fuel options to supply power taking into account load projections, emission costs, fuel price projections, plant performance, and capital and operating cost estimates. The emissions costs, in the form of a tax or allowance price (or another equivalent mechanism), consider CO_2, SO_2, and NO_x emissions.

STUDY ASSUMPTIONS

This study evaluates IGCC market potential in the year 2010 because significant advances in IGCC and other power generation technologies should be adequately demonstrated and ready for commercialization by then. Also, implementation of CO_2 emission reduction programs within the next 5-10 years will increase compliance option evaluations, and CO_2 allowance prices should be fairly well established.

The baseload load growth was assumed to be 1.65 percent per annum. Each power pool was assumed to supply its own power needs with no interpool wheeling.

As mentioned above, the northeast power generation market consists of three power pools. These are the Pennsylvania, New Jersey, Maryland Pool (PJM), the New York Power Pool (NYPP), and the New England Power Exchange (NEPEX). Base load power is classified into coal-fired, nuclear, hydro, and "other" categories. The "other" category includes power purchases and waste-fired plants. A breakdown of 1996 total and baseload capacity for each of the power pools is shown in Table 1.

Annual demand curves for each power pool are expressed as an average, peak, and minimum load in Table 1. The Regional Compliance Model statistically sums these demands on an annual basis. For this study, the loads are further broken down into a the five-month summer ozone – May through September – season and a seven-month non-ozone season to appraise the impact of NO_x compliance.

For the northeast region, a prediction of the potential power market for the year 2010 is made by applying the U. S. Energy Information Administration (EIA) load growth projections[2] to the northeast region. Baseload power growth for the year 2010 is assumed to be the same as general load growth. Future nuclear and hydro capacity is based on EIA growth projections . The contribution of "other" capacity sources is assumed to remain constant – no growth or loss of generation units. Fossil fuel plants, comprised of existing coal-fired, new coal-fired, and new gas-fired units, will provide the remaining baseload power. Replacement of existing coal-fired units with lower cost, more efficient coal- or gas-fired technologies generally increases the fossil capacity at existing sites. As required, additional new coal- or gas-fired units are installed at these sites to provide the remaining baseload capacity requirement. A breakdown of the projected 2010 total and baseload capacity for each of the power pools is shown in Table 2.

It is assumed that existing power plants continue to operate until they become uneconomic. Pollution allowances must be purchased for all emissions produced by the plants. It is assumed that the costs of emission allowances are:

- SO2 @ $354/ton
- NOx @ $1,723/ton (ozone), $259/ton (other)
- CO2 @ $0-$100/tonne

The price of fuel is assumed to escalate. Coal is assumed to escalate at minus 0.69 percent per year and natural gas from a low of 0.54 percent per year to a high of 4.5 percent per year.

The coal/natural gas fuel price differential is an important factor in determining the market potential of all coal-fired technologies, including IGCC. This study uses site-specific 1997 coal characteristics and delivered fuel price as a baseline to evaluate each unit. The average delivered coal price for all existing coal-fired units in 1997 was $1.45/MM Btu and the price range was $0.88-$1.94/MM Btu. Sites having a high delivered coal price are more likely to fuel switch to gas in the existing unit or replace the current unit with a NGCC plant. These sites will probably not be economically attractive for installing a new coal unit to satisfy new capacity needs.

It is assumed that the current coal is used in the year 2010. Although coal switching is possible, the evaluation of this option is very complex and beyond the scope of this study. Coal switching (to Powder River Basin or southern Appalachian coals) in the northeast region is less likely to occur as compared with the Midwest and southeast regions.

The EIA industrial coal price forecast[2] for the U.S. was used rather than the utility price forecast to be conservative. Utility coal prices are forecasted to decline 1.47%/yr less than the general rate of inflation to 2010 while industrial coal prices are forecasted to decline only 0.69%/yr during the same period.

Ozone and non-ozone season natural gas prices for each power pool in 1997 are used as a cost basis. These are shown in Table 3. A range of annual price escalation rates ranging from 0.54% to 4.5% above the general rate of inflation is examined to decide the impact of gas price in year 2010 on IGCC market potential. The 0.54% annual escalation rate is based on the 1998 EIA forecast[2] for the delivered natural gas price to the U.S. utility sector. The higher price escalations take into account that mandated carbon emission reduction programs will increase both the demand and price of natural gas.

In the economic analyses, leveraged financing is used with an expected return on equity (ROE) of 15 percent. The financial factors used in the study reflect a non-regulated utility industry and are similar to project financing parameters currently used by non-utility generators (NUGs). These are characterized by leveraged financing, a higher return on investment and a somewhat shorter project life than typical for a regulated utility power project. The total project life ranges from 26 to 28 years based on a common 25 year operating life and construction periods ranging from 1 to 3 years. The financial factors used and construction period of each option are shown in Table 4.

METHODOLOGY

The modified CONSOL RCM[1] model was used to evaluate the options for the Northeast region. All of the new capacity options were evaluated at a fixed capacity factor of 80 percent and the mix of technologies giving the lowest cost of electricity was chosen. Two parameters were investigated in this study. These were the price of natural gas and the imposition of a carbon tax. Natural gas price was varied from a low escalation rate of 0.54 percent per year to a high rate of 4.5 percent per year and the carbon tax was varied from $0/tonne to $100/tonne of carbon.

Several compliance options are available to the plants in the region. These are:

- To purchase pollution allowances for SO_2, NOx, and CO_2. For an existing coal-fired unit, one option is to continue operating the plant "as-is" and purchase allowances rather than reducing emissions. This strategy can be attractive because no emission control hardware-related capital charges and O&M costs are incurred. For this strategy to be cost-effective, the total cost of allowances must be small.

- To retrofit emission controls. For the existing coal-fired unit, another option is to modify the unit by retrofitting emission control hardware for SO_2 and/or for NO_x. The only SO_2 emission control option evaluated for unscrubbed units is a retrofit limestone forced oxidation (LSFO) wet scrubber. The scrubber is designed to remove 95% SO_2 with large absorbers and no spares. The maximum MW capacity per absorber is 650 MW. This is the current technology limit. It is also assumed that the flue gas streams from large multi-unit power stations are aggregated into a single flue gas desulfurization (FGD) unit. This approach reduces cost and has been demonstrated commercially at several plants. Various NO_x control options and combinations of options are evaluated. The NO_x emission levels of the existing units are based on data reported for 1996. The control options evaluated include: low-NO_x burners, selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), and combinations of these.

- Fuel switching. Fuel switching from coal to natural gas is a low capital cost option for reducing SO_2, NO_x, and CO_2 emissions in existing units. The disadvantages are the decrease in boiler efficiency and the high fuel cost. Net power output increases slightly because reduced duty of the fuel and ash handling systems, the pulverizers and the electrostatic precipitator (ESP) are not required. It is assumed that a natural gas pipeline is near each plant. As a result, the only capital cost incurred for this option is for the installation of gas burners. The two options evaluated are seasonal and year-round fuel switching. Seasonal (May through September) fuel switching is evaluated to minimize NO_x emission costs during the ozone season when allowance costs are very high. Fuel switching is evaluated based on the delivered ozone and non-ozone season natural gas prices specific to each power pool.

- Repowering. Repowering is an option that increases capacity, improves power generation performance, reduces emissions, and preserves part of the existing asset for continued use. Generally, repowering is the replacement of the original unit steam supply system and integration of the new steam system into the remainder of the plant. The steam turbine-generator is the most critical item reused. The reuse of other plant systems is maximized. Some systems may require upgrading or refurbishment. The evaluation of repowering is very site specific and very limited information on performance and cost is available. This study provides an initial and limited evaluation of the repowering option. Criteria were developed to decide which existing coal units are suitable for repowering, and for the performance and capital and operating costs of the repowered plants. The repowering technologies examined are natural gas-fired G-frame NGCC, and coal-fired advanced IGCC and advanced PFBC. Only single train repowering designs were considered. For example, a single gas turbine, single steam turbine NGCC design was evaluated, while a design with two gas turbines and one steam turbine was not considered. This limitation probably results in underestimating the potential for both coal and gas repowering of existing plants.

- To replace an existing unit with a new unit. Twelve technology options were evaluated as alternatives for replacing the existing units. It was assumed that only the current unit site and general support facilities are reused. The original unit is abandoned and a new unit (from coal handling to the stack) is built. The gas-fired options include three NGCC technologies based on F, G, and H frame gas turbines. The pulverized-coal (PC) options include subcritical, supercritical, ultrasupercritical, and advanced ultrasupercritical technologies. The PCs are equipped with a limestone forced oxidation (LSFO) scrubber, low -NO_x burners, and a SCR. The IGCC options include two currently available technologies and one advanced technology. The IGCC market potential is evaluated at each technology level to decide the impact of technology advancement. The pressurized fluidized bed combustion (PFBC) options include one currently available and one advanced technology. The performance and costs of the replacement plant technologies are listed in Table 5.

- To add new units to increase capacity. The same technology options considered for replacement units are considered for units providing new capacity. Since units providing new capacity will be built at existing sites and use the same coal (if coal-fired), the performance and cost of the new capacity units are the same as the replacement units. These are listed in Table 5. It is assumed that adequate space exists at each existing site to construct one or more additional units.

These options reflect the desire of utilities to continue to use current generating assets and only replace a unit if economically justified.

A database of firing mode, coal characteristics, existing emission control equipment, power generation performance, coal cost and emissions for all existing coal-fired units as well as performance and cost estimates of new plant and repowering technologies allows unit-specific calculation of the cost of electricity (COE) of each compliance option. The

COE consists of the capital charge, fuel cost, operating and maintenance (O&M) costs, and emission allowance costs. The COE is the deciding factor in selecting the compliance option. It is assumed that no coal-fired unit is retired unless economically justified. The COE is the bus bar cost of power excluding transmission, distribution, and corporate overhead.

Although the actual replacement market will include nuclear and hydro units, these units would be replaced for reasons other than emission compliance. No unit-specific information was available to consider a repowering option. Thus, the only option considered in this study for a decline in nuclear and hydro capacity is the construction of a new coal- or gas-fired power plant. Because the new unit is not limited to the existing site, it is considered as a market for new capacity.

Additional coal- or gas-fired generating units are required to supply baseload capacity not supplied by existing coal, nuclear, and hydro units, “other” sources, and replacement units. In general, the need for new unit capacity will be lower as existing coal-fired units are replaced. This is because the coal plants that are replaced are characterized by their small generating capacity (and low efficiency). For example, the Pennsylvania Electric Co. Warren Units 1 and 2, which have a nameplate capacity of 42 MW (and a 13, 443 Btu/kWh heat rate) each, would most likely be replaced with units ranging in capacity from 246 MW to 648 MW.

The Regional Compliance Model portion of the study treats each power pool separately in terms of new capacity needs. Evaluating each pool separately allows solutions unique to the pool to be determined. Each power pool’s need for new capacity will be dependent on the compliance options chosen at each existing coal-fired unit, fuel cost, emission costs, and the amount of nuclear and hydro baseload capacity.

It is assumed that all new capacity is located at existing plant sites. All new plant options are evaluated at each existing site. The new plants are installed at the sites where the COE is lowest. One or more new units can be installed at each site. In this manner, the COE for each power pool’s new capacity is minimized.

The RCM model was then used over a range of conditions of varying natural gas price and carbon taxes to evaluate the various replacement and new plant options that gave the lowest cost of power.

The replacement and new plant options that were considered were:

- Natural gas combined cycle (NGCC) plants. Two technology levels for NGCC plants were evaluated. These were a current G Turbine design with a heat rate of 6,743 Btu/kWh and a capital cost of $524 per kW installed capacity and an advanced H turbine design with a heat rate of 6,396 Btu/kWh and a capital cost of $461 per kW.
- Sub, super, and ultrasupercritical pulverized coal units. For these the heat rate varied from 9,100 Btu/kWh to 8,250 Btu/kWh and the installed capital from $1,130/kW to $1,170/kW.

- Current and advanced pressurized fluidized bed combustion (PFBC) technology. The current technology performance is assumed to have a heat rate of 8,350 Btu/kWh and an installed capital of $1,190/kW. For the advanced technology (APFB) the heat rate is 7,270 Btu/kWh and the capital is $1,000 per kW.
- Current and advanced IGCC. The current technology performance for IGCC is assumed to consist of both air and oxygen blown technologies. This analysis assumes that the current IGCC heat rate and capital cost of the air-blown and oxygen-blown systems are 8,106 Btu/kWh and $1,392/kW, and 8,522 Btu/kWh and $1,241/kW, respectively. For the advanced IGCC technologies, it is assumed that the advanced air-blown system has a heat rate of 6,870 Btu/kWh and a capital cost of $961 per kW, and the advanced oxygen-blown technology has a heat rate of 6968 Btu/kWh and a capital cost of $1,087 per kW.

RESULTS AND DISCUSSION

REGIONAL COMPLIANCE MODEL RESULTS

IGCC market penetration was evaluated at two levels of IGCC technology development over a matrix of market conditions. The market conditions examined encompass natural gas price escalation rates of 0.54%-4.50% per year and carbon taxes of $0-$100 per tonne of carbon. The coal price escalation rate and SO_2 and NO_x emission allowance prices were fixed in the study.

Current Technology IGCC

The results of the IGCC market penetration study show that the most critical factor affecting deployment of IGCC to the year 2010 is the level of technology advancement that can be achieved. Without improvements in cost and performance compared to the current state of development, **no** IGCC market penetration is expected in either the replacement unit or new capacity market segments regardless of market conditions. This analysis assumes that the current IGCC heat rate and capital cost of the air-blown and oxygen-blown systems are 8,106 Btu/kWh and $1,392/kW, and 8,522 Btu/kWh and $1,241/kW, respectively. Although site- and market condition-specific, IGCC power costs from current technology are greater than other new plant, coal-fired technology options. At a representative plant site in the PJM power pool, for example, current technology IGCC power cost is 2-22% greater than competing coal-fired technologies under business-as-usual (BAU) market conditions. BAU is defined as $0/tonne carbon tax and the low gas escalation rate of 0.54 percent per annum.

Coal-fired technology options installed in preference to current technology IGCC are subcritical pulverized-coal (PC) units at lower carbon taxes and higher efficiency, and advanced pressurized fluidized bed combustor (PFBC) units at higher carbon taxes. Advanced, natural gas-combined cycle (NGCC) plants dominate the replacement plant and new capacity market segments at low gas price escalation rate and high carbon tax market conditions. Advanced NGCC market penetration declines at high gas price escalation rates and low carbon tax market conditions. A significant number of existing coal-fired plants purchase emission allowances or retrofit emission control equipment as a compliance strategy at lower carbon taxes. Increasing the carbon tax from $50 to $100/tonne C significantly changes the compliance strategy at existing units toward plant replacement with higher efficiency coal- and natural gas fired technologies.

Figure 1 shows the results of the RCM model for $0 and $100 per tonne carbon tax for the low and high natural gas escalation rates. At the low natural gas escalation the price of gas in 2010 would be about $3.50 /MMBtu. At the high escalation rate the price of gas would be about $5/MMBtu. At $0 carbon tax and 0.54 percent gas escalation the total number of power plants would be 170 in the year 2010. Of these 60 would comply by buying emission allowances, 46 would retrofit controls, 4 would be retired, 4 would be NGCC replacement plants, and 60 would be new capacity NGCC plants. The total fossil baseload requirement in 2010 is estimated to be about 43 GW (see Table 2). Of this about 22 GW is produced at existing sites and about 22 GW is installed new capacity.

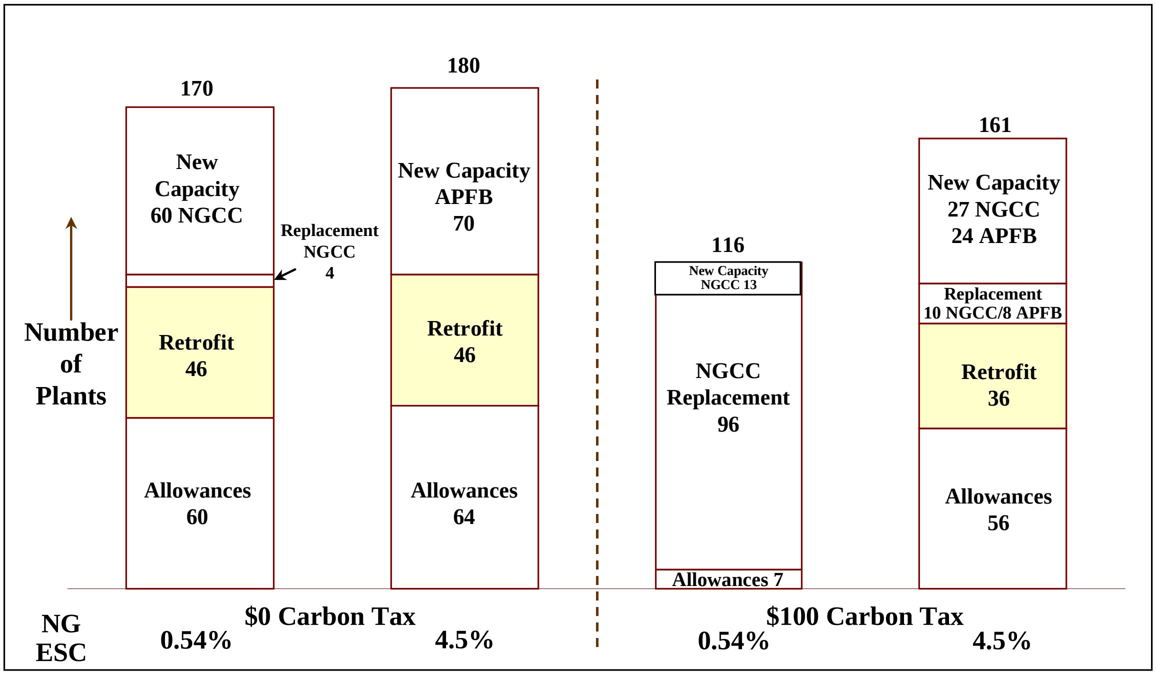

Figure 1: Technology Mix in the Northeast U.S. in 2010 Assuming Current IGCC Technology

At the high gas escalation rate and $0 carbon tax there would be a total of 180 plants. Of these 64 would purchase allowances, 46 would retrofit controls. New capacity would be provided by 70 advanced pressurized fluid bed combustion power plants (APFB). The cost of natural gas is now so high that the preferred power plant for new capacity additions would be the coal fired APFBs rather than the NGCC plants. The total demand in 2010 is estimated to be about 43 GW. Of this about 21 GW is produced at existing sites and 23 GW is installed new capacity.

For the case of $100 per tonne carbon tax and low gas escalation there would be a total of 116 plants. Of these only 7 would be able to purchase allowances, none would retrofit controls, 103 plants would be retired, 96 would be replaced by NGCC plants, and 13 new capacity NGCC plants would be built. Of the total demand of about 43 GW, 39 GW would be produced at existing sites and about 4 GW would be installed new capacity. Thus under this scenario with low natural gas prices and high carbon tax older existing coal fired plants would be forced to shut down and be replaced by NGCC plants.

In the final scenario depicted in Figure 1 that of high gas price escalation and $100 per tonne carbon tax there would be 161 plants. Of these 56 would buy allowances, 36 would retrofit, 17 would be retired, 10 would be replaced by NGCC plants, 8 by APFB plants, and new capacity additions would include 27 NGCC plants and 24 APFB plants.

Thus high gas prices tend to retain existing coal fired units even at a high carbon tax and new capacity is provided by a combination of NGCC and advanced coal fired APFB units. Of the total demand of about 43 GW, 26 GW would be produced at existing sites and about 17 GW would be installed new capacity.

Advanced IGCC

Performance and cost improvements from the current level of development to an "advanced" level will allow IGCC to effectively compete with advanced NGCC and with other coal-fired technologies in the power market. Advanced technology IGCC has significant market penetration under most market conditions. The advanced technology heat rate and capital cost assumed in this study are 6,870 Btu/kWh and $961/kW respectively, based on recent estimates by Parsons[3]. This represents a 16-20% heat rate improvement and a 23-30% capital cost reduction from current IGCC technologies. At this performance/cost level, IGCC technology is **superior** to all other coal-fired technologies examined. At a representative plant site in the PJM power pool, for example, advanced technology IGCC power cost is 15-23% lower than current technology IGCC and 6-13% lower than competing coal-fired technologies under BAU market conditions.

Over the range of market conditions examined, the maximum market penetration for IGCC occurs at the highest gas price escalation and the highest carbon tax (see Figure 2). The highest natural gas escalation rate is 4.5%/yr, equivalent to a gas price increase from about $3/MMBtu in 1999 to about $5/MMBtu in 2010. The highest carbon tax is $100/tonne C. Under these market conditions, total IGCC penetration in the Northeast would be 71 plants with a total dispatchable capacity (net capacity based on availability) of 25 GW. With these conditions, IGCC dominates the power market over advanced NGCC and only demand and other compliance options available at existing plants limit the market penetration. The high gas price escalation, which favors coal, more than offsets the carbon tax, which favors gas. Forty six per cent of the 110 existing coal-fired units, or 33 units, are replaced and repowered with IGCC. For the majority of existing coal-fired units, emission allowance purchases or emission control retrofits are still the most cost-effective compliance strategies. These compliance strategies avoid the capital charges associated with new plant construction.

Even advanced IGCC has no market penetration at the lowest gas price escalation and highest carbon tax (0.54%/yr and $100/tonne C) condition (see Figure 2). At this condition, advanced NGCC (assumed to be an H turbine facility with a heat rate of 6,396 Btu/kWh and a capital cost of $461/kW as estimated in the Parson's study) again dominates the power market despite the significant advances in IGCC technology. In this scenario 103 coal-fired plants are retired and replaced by 96 NGCC plants. Thirteen-(13) new capacity NGCC plants are added and only 7 existing plants purchase allowances.

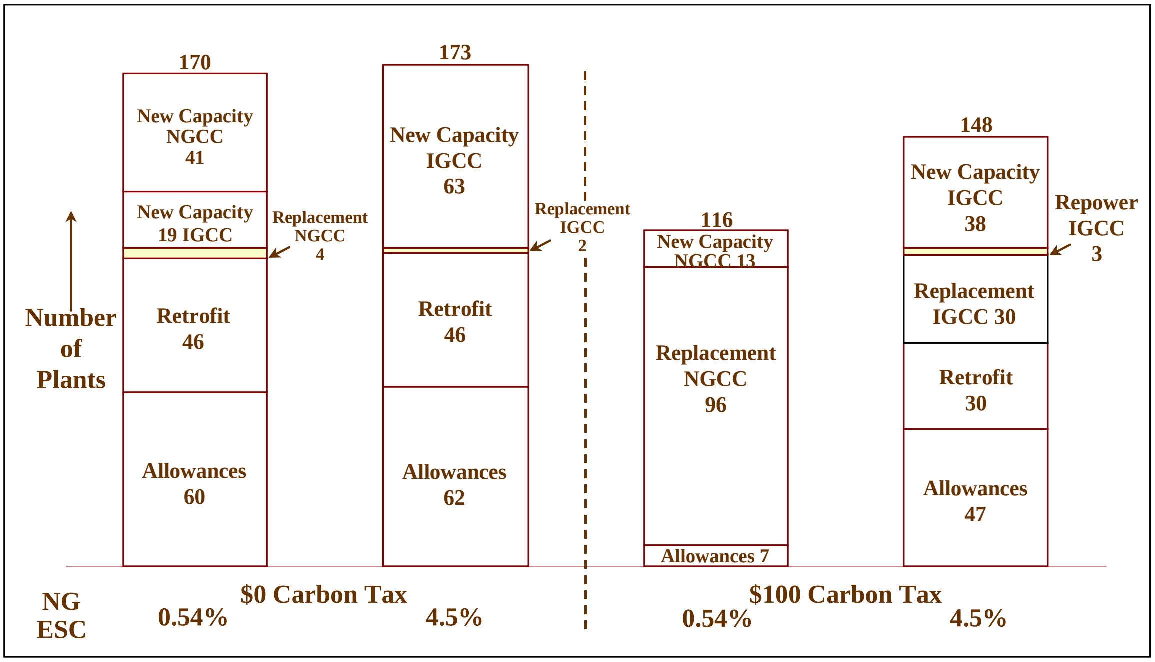

Figure 2: Technology Mix in the Northeast U.S. in 2010 Assuming Advanced IGCC Technology

Advanced IGCC has a significant market penetration at business-as-usual (BAU) market conditions ($0 carbon tax and 0.54 percent gas escalation). At this condition, total IGCC penetration is 19 plants with a total dispatchable capacity of 7 GW. All IGCC capacity is constructed to satisfy new capacity requirements. IGCC shares the new capacity market segment with advanced NGCC. The NGCC market penetration is 15 GW. Ninety-nine percent of the existing coal-fired units purchase emission allowances (60 plants) or retrofit emission control equipment (46 plants) as a compliance strategy. Four existing coal-fired plants are replaced with advanced NGCC.

Figure 3 shows the overall results for this study for both changes in carbon tax and natural gas price escalation. Advanced IGCC dominates the market at the 4.5% gas price escalation rate for all carbon tax ranges analyzed. Over the $0-$100/tonne C tax range examined, IGCC market penetration is fairly constant at 65-71 plants (27-29 GW). High gas prices more than offset carbon taxes and results in the market favoring the low-cost advanced coal-fired technology. No NGCC plants are built under this high natural gas escalation condition.

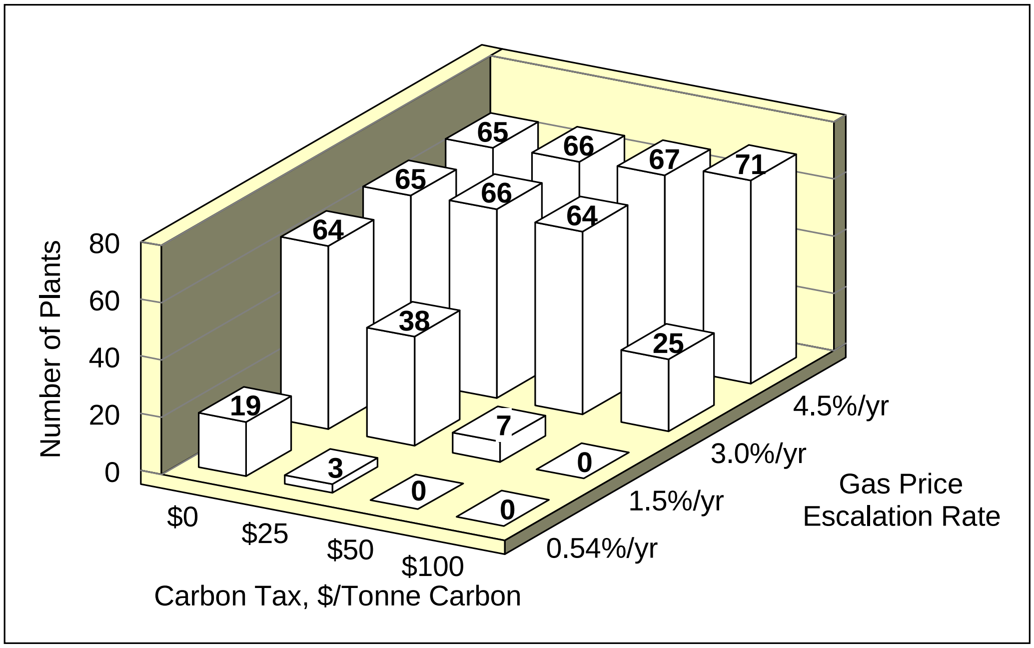

Figure 3: Advanced IGCC Market Potential in the Northeast U.S. in 2010.

Advanced IGCC dominates the market at the 3.0% gas price escalation rate at carbon taxes of $0-$50/tonne C and shares the market with NGCC at a $100/tonne C tax. At carbon tax levels of $0-$50/tonne C, IGCC market penetration is fairly constant at 64-66 plants (22-23 GW). Two NGCC plants are built. Coal competes with gas at a $100/tonne C tax level. Here, IGCC market penetration decreases to 25 plants. NGCC market penetration is 48 plants (18 GW).

Advanced IGCC dominates the market at the 1.5% gas price escalation rate only if there are no carbon taxes. The IGCC market share declines to zero as the carbon tax level increases to $100/tonne C. Without a carbon tax, IGCC market penetration is 64 plants (23 GW). IGCC competes with NGCC at carbon taxes levels of $25-$50/tonne C. The market just favors coal at a $25/tonne C tax and gas at a $50/tonne C tax. NGCC dominates the market at the $100/tonne C tax level and no coal-fired plants are built.

Advanced IGCC shares the market with NGCC at the 0.54% gas price escalation rate at zero carbon tax (19 plants). At $25/tonne C tax, IGCC share drops to only 3 plants. IGCC has no market penetration at carbon taxes of $50-$100/tonne C. NGCC dominates the market at carbon tax levels of $50 to $100/tonne C and no coal-fired plants are built.

Over the range of market conditions examined, the majority of IGCC plants are constructed to satisfy new capacity requirements. The new capacity market penetration is strongest under conditions of high gas price escalation and no carbon tax, but is still significant over most of the range examined. Carbon taxes reduce the market penetration because IGCC competes with NGCC in this market segment. Higher gas price escalations always favor coal-based technologies.

A somewhat more limited market for IGCC is the replacement of existing coal-fired units. This market penetration also increases with higher gas price escalation. The greatest replacement plant market penetration occurs at a medium to high carbon tax. This level of carbon tax provides an economic incentive for power generators to retire existing, lower efficiency coal-fired units in favor of high efficiency IGCC plants. Without a carbon tax, generators will comply with SO_2 and NO_x emission regulations by purchasing allowances and/or modifying existing units to reduce emissions. A significant number of existing coal-fired units will continue to operate even at a carbon tax of $100/tonne C if natural gas prices escalate at 1.5 percent per year and higher..

Details of these results are shown in Tables 1,2 and A1 and A2 in the appendix.

CONCLUSIONS

The conclusions of the study are:

1. If IGCC is to be a future player in the U.S. power market, it is imperative to continue development of IGCC technology to reduce capital costs to about $1000/kW and improve heat rates to less than 7,000 Btu/kWh. If these targets can be achieved, IGCC can then effectively compete with other coal-fired technologies and, more importantly, with NGCC technology. IGCC will be the **coal-fired technology of choice** if the performance and cost estimates used in the study are achieved.

2. Advanced IGCC technologies that achieve these targets can achieve significant market penetration even under business-as-usual market conditions. IGCC and NGCC will share the market for new capacity and existing coal-fired units will continue operation.

3. The imposition of a carbon tax and the rate of gas price escalation are important factors that will affect IGCC penetration in both the replacement unit and new capacity market segments. Carbon taxes have a different market penetration impact on the replacement unit and new capacity market segments because additional compliance options are available in the replacement unit market. High carbon taxes and low natural gas escalation force the retirement of older low efficiency coal-fired units. However, at high natural gas escalation even high carbon taxes will not force closure of older coal fired plants. They will purchase allowances and retrofit emission controls. Replacement and new capacity will be provided by advanced IGCC plants.

REFERENCES

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2. Energy Information Administration, U.S. Department of Energy, Annual Energy outlook 1998 with Projections to 2020, DOE/EIA-0383 (98) , December 1977.
3. “Market-Based Advanced Coal Power Systems - Final Report”, prepared by Parsons Infrastructure and Technology for the United States Department of Energy, Office of Fossil Energy, Contract No. DE-AC01-94FE62747, Task 22/36, December 1998.

TABLES

Table 1
Historical Load and Capacity Data For 1996

Power Pool	NEPEX		NYPP		PJM		Total	Total
Season	Ozone	Other	Ozone	Other	Ozone	Other	Ozone	Other
Loads, MW								
Average	12,856	13,194	17,129	16,739	28,126	27,599	58,111	57,532
Peak	19,507	19,056	25,587	22,942	44,302	40,746	89,396	82,744
Minimum	7,520	7,752	10,142	10,717	16,525	16,834	34,187	35,303
Capacity, MW								
Coal-Fired Baseload	2,601	2,619	3,795	3,763	18,756	19,004	25,152	25,385
Non-Coal Baseload								
Hydro	493	580	2,887	3,000	221	338	3,601	3,918
Nuclear	3,003	3,762	4,394	3,734	8,997	9,460	16,394	16,956
Other	4,630	4,574	3,835	4,989	5,520	5,250	13,985	14,813
Tot Non-Coal	8,126	8,916	11,116	11,723	14,738	15,048	33,980	35,687

Table 2
Projected Load and Capacity Data For 2010

Power Pool		NEPEX		NYPP		PJM		Total	Total
Season		Ozone	Other	Ozone	Other	Ozone	Other	Ozone	Other
Loads, MW	Growth (%/yr)								
Average MW	1.65%	16,175	16,600	21,551	21,061	35,388	34,724	73,114	72,386
Peak MW	1.65%	24,543	23,976	32,193	28,865	55,740	51,266	112,476	104,107
Minimum MW	1.65%	9,462	9,753	12,760	13,484	20,791	21,180	43,013	44,418
Capacity, MW									
Non-Coal Baseload									
Hydro MW	-0.19%	480	565	2,811	2,921	215	329	3,506	3,815
Nuclear MW	-0.88%	2,653	3,324	3,883	3,299	7,950	8,359	14,486	14,982
Other MW	0.00%	4,630	4,574	3,835	4,989	5,520	5,250	13,985	14,813
Tot Non-Coal		7,764	8,463	10,529	11,210	13,685	13,938	31,977	33,610
Fossil Baseload Rqmt		5,733	6,050	8,232	8,274	28,456	28,906	42,421	43,229

Table 3
1997 Natural Gas Delivered Prices

Power Pool	Year-round	Ozone Season	Non-Ozone Season
NEPEX	$3.100	$2.809	$3.308
NYPP	$2.901	$2.597	$3.119
PJM	$3.131	$2.803	$3.366

Table 4
Financial Factors and Construction Periods

Financial Factors	
ROI, %	15.00%
Project Life, years	26-28
Construction Period, years	1-3
Operating Life, years	25
General Infltion Rate, %/yr	3.00%
% Financed	66.00%
Loan Interest	8.00%
Loan Term (Years)	12
Tax Rate	34.00%
Prop. Taxes & Ins.	1.50%
Tax Life	20
Depreciation	150% declining balance
Salvage Value	0
Construction Period, years	
Existing Plant Modifications	
LNB	1
LNB/OFA	1
SNCR (with or without LNB or LNB/OFA)	1
SCR (with or without LNB or LNB/OFA)	2
FGD	2
Fuel Switch	1
Repowering	
NGCC	2
IGCC	3
PFBC	3
New Units	
PC	3
NGCC	2
IGCC	3
PFBC	3
CoCo	3

Table 5: New Plant Performance and Cost
(Representative Example in the PJM Power Pool - 2010)

Technology	NGCC			Pulverized Coal			
Version	FA Turbine	G Turbine	H Turbine	Subcritical	Supercritical	UltraSupercritical	UltraSupercritical
Status	Current	Current	Advanced	Current	Current	Current	Advanced
Performance							
Gross Capacity, MW	246.2	334.0	403.3	334.0	365.6	403.34	415.9
Net Output, MW	238.8	326.0	395.0	326.1	354.6	395.0	398.0
Net Heat Rate, Btu/kWh	7,359	6,743	6,396	9,077	8,568	8,251	8,266
Availability, %	93	93	93	88	88	88	88
Liquid Product Output, BBl/day	0	0	0	0	0	0	0
Capacity Factor, %	80	80	80	80	80	80	80
Environmental Performance							
NOx Reduction %	N/A	N/A	N/A	91	91	91	91
SO2 Removal, %	N/A	N/A	N/A	0.95	0.95	0.95	0.95
CO2 Removal, %	0	0	0	0	0	0	0
Emissions, lb/MWh							
NOx	0.86	0.2	0.19	4.03	1.36	3.21	0.65
SO2	0	0	0	2.98	1.41	1.36	1.70
CO2	868	795	754	1,724	1,627	1,567	1,570
Capital Cost							
Plant Cost, $MM	$164	$171	$182	$449	$472	$589	$423
Plant Cost, $/kW	$687	$524	$461	$1,129	$1,173	$1,170	$1,064
Power Cost, $/MWh (1)							
Capital Charge	$14.05	$10.72	$9.43	$24.52	$25.48	$25.42	$23.11
Coal (2)	$0.00	$0.00	$0.00	$14.70	$13.87	$13.36	$13.38
Natural Gas (3)	$24.71	$22.65	$21.48	$0.00	$0.00	$0.00	$0.00
Fixed Cost	$2.32	$2.28	$2.27	$3.83	$3.93	$3.12	$3.61
Variable O&M	$0.39	$1.28	$1.35	$2.25	$3.51	$1.61	$2.11
Catalyst Replacement	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.99
Emission Allowances (4)	$0.37	$0.09	$0.08	$2.28	$0.84	$1.63	$0.59
Liquid Product Revenue (5)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Cost	$41.84	$37.02	$34.62	$47.58	$47.63	$45.13	$43.79

Notes:
1) Business-as-usual market conditions of 0.54 %/yr gas price escalation and no carbon tax
2) Delivered coal price of $1.62/MM Btu for a 2.44 % S, 10.7 % ash, 12,669 Btu/lb product.
3) Delivered natural gas price of $3.01/MM Btu (ozone season) and $3.61/MM Btu (non-ozone season).
4) Includes NOx and SOs emission allowance costs
5) Liquids value is $30/bbl on crude oil at $21.

Table 5 (Concluded): New Plant Performance and Cost
(Representative Example in the PJM Power Pool - 2010)

Technology	IGCC				PFBC		Coproduction	
Version	Air Blown	Ox Blown	Air Blown	Ox Blown	Bubbling Bed	Circulating Bed	UltraSupercritical	UltraSupercritical
Status	Current	Current	Advanced	Advanced	Current	Advanced	Current	Advanced
Performance								
Gross Capacity, MW	227	648.5	411.2	490.1	453.3	401.8	460.2	450.3
Net Output, MW	214.0	543.2	398.1	427.7	424.6	371.1	460.6	423.5
Net Heat Rate, Btu/kWh	8,106	8,522	6,870	6,968	8,354	7,269	11,721	9,258
Availability, %	88	88	88	88	88	88	88	88
Liquid Product Output, BBl/day	0	0	0	0	0	0	6,787	3,393
Capacity Factor, %	80	80	80	80	80	80	80	80
Environmental Performance								
NOx Reduction %	90	98.9	93.8	93.8	70.2	73.2	95.5	95.5
SO2 Removal, %	98.5	99.0	99.5	99.5	90	94.63	98	98
CO2 Removal, %	0	0	0	0	0	0	5.8	10.7
Emissions, lb/MWh								
NOx	0.71	0.08	0.37	0.38	2.19	1.71	0.18	0.10
SO2	0.5	0.37	0.14	0.14	3.43	1.60	0.65	0.35
CO2	1539	1618	1305	1323	1,586	1,380	1,819	1,229
Capital Cost								
Plant Cost, $MM	$298	$674	$383	$465	$505	$372	$656	$454
Plant Cost, $/kW	$1,392	$1,241	$961	$1,087	$1,190	$1,001	$1,425	$1,072
Power Cost, $/MWh (1)								
Capital Charge	$30.23	$26.96	$20.87	$23.62	$25.85	$21.74	$30.95	$23.28
Coal (2)	$13.12	$13.80	$11.12	$11.28	$13.52	$11.77	$12.82	$6.97
Natural Gas (3)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$12.77	$16.63
Fixed Cost	$5.51	$5.25	$5.28	$5.50	$4.17	$5.08	$3.94	$2.89
Variable O&M	$1.56	-$0.24	$0.06	$0.18	$2.82	$2.86	$1.71	$0.93
Catalyst Replacement	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Emission Allowances (4)	$0.40	$0.10	$0.19	$0.19	$1.56	$1.03	$0.20	$0.10
Liquid Product Revenue (5)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$10.86	-$5.91
Total Cost	$50.82	$45.87	$37.52	$40.77	$47.92	$42.48	$51.53	$44.89

Notes:

1) Business-as-usual market conditions of 0.54 %/yr gas price escalation and no carbon tax

2) Delivered coal price of $1.62/MM Btu for a 2.44 % S, 10.7 % ash, 12,669 Btu/lb product.

3) Delivered natural gas price of $3.01/MM Btu (ozone season) and $3.61/MM Btu (non-ozone season).

4) Includes NOx and SOs emission allowance costs

5) Liquids value is $30/bbl on crude oil at $21.

APPENDIX

Table 1
Power Market Potential For IGCC In The Northeast U. S. (Current IGCC)

Gas Price Escalation, %/yr	0.54%				1.50%			
Carbon Tax, $/Tonne C	$0	$25	$50	$100	$0	$25	$50	$100
Number of Plants								
Replacement Plants-IGCC	0	0	0	0	0	0	0	0
New Capacity-IGCC	0	0	0	0	0	0	0	0
Replacement Plants-Other Coal (inc CoCo)	0	0	0	0	0	0	0	0
New Capacity-Other Coal (inc CoCo)	0	0	0	0	3	0	0	0
Replacement Plants-Gas	4	12	38	96	1	8	25	73
New Capacity-Gas	60	52	33	13	59	56	41	12
Total of above	64	64	71	109	63	64	66	85
Dispatchable Capacity, MW net								
Replacement Plants-IGCC	0	0	0	0	0	0	0	0
New Capacity-IGCC	0	0	0	0	0	0	0	0
Replacement Plants-Other Coal (inc CoCo)	0	0	0	0	0	0	0	0
New Capacity-Other Coal (inc CoCo)	0	0	0	0	980	0	0	0
Replacement Plants-Gas	1,470	4,409	13,960	35,268	367	2,939	9,184	26,818
New Capacity-Gas	22,043	19,104	12,123	4,776	21,675	20,573	15,062	4,409
Total of above	23,512	23,512	26,084	40,044	23,022	23,512	24,247	31,227
Installed Capacity, MW gross								
Replacement Plants-IGCC	0	0	0	0	0	0	0	0
New Capacity-IGCC	0	0	0	0	0	0	0	0
Replacement Plants-Other Coal (inc CoCo)	0	0	0	0	0	0	0	0
New Capacity-Other Coal (inc CoCo)	0	0	0	0	1,205	0	0	0
Replacement Plants-Gas	1,613	4,840	15,327	38,720	403	3,227	10,083	29,444
New Capacity-Gas	24,200	20,974	13,310	5,243	23,797	22,587	16,537	4,840
Total of above	25,814	25,814	28,637	43,964	25,406	25,814	26,620	34,284
Gas Price Escalation, %/yr	3.00%				4.50%			
Carbon Tax, $/Tonne C	$0	$25	$50	$100	$0	$25	$50	$100
Number of Plants								
Replacement Plants-IGCC	0	0	0	0	0	0	0	0
New Capacity-IGCC	0	0	0	0	0	0	0	0
Replacement Plants-Other Coal (inc CoCo)	0	0	0	0	0	1	6	8
New Capacity-Other Coal (inc CoCo)	70	40	4	0	70	69	64	24
Replacement Plants-Gas	0	2	8	45	0	0	0	10
New Capacity-Gas	0	26	52	27	0	0	0	27
Total of above	70	68	64	72	70	70	70	69
Dispatchable Capacity, MW net								
Replacement Plants-IGCC	0	0	0	0	0	0	0	0
New Capacity-IGCC	0	0	0	0	0	0	0	0
Replacement Plants-Other Coal (inc CoCo)	0	0	0	0	0	327	1,960	2,602
New Capacity-Other Coal (inc CoCo)	22,865	13,066	1,307	0	22,865	22,538	20,905	7,839
Replacement Plants-Gas	0	735	2,939	16,532	0	0	0	3,674
New Capacity-Gas	0	9,552	19,104	9,919	0	0	0	9,919
Total of above	22,865	23,352	23,349	26,451	22,865	22,865	22,865	24,034
Installed Capacity, MW gross								
Replacement Plants-IGCC	0	0	0	0	0	0	0	0
New Capacity-IGCC	0	0	0	0	0	0	0	0
Replacement Plants-Other Coal (inc CoCo)	0	0	0	0	0	402	2,411	3,170
New Capacity-Other Coal (inc CoCo)	28,124	16,071	1,607	0	28,124	27,722	25,714	9,643
Replacement Plants-Gas	0	807	3,227	18,150	0	0	0	4,033
New Capacity-Gas	0	10,487	20,974	10,890	0	0	0	10,890
Total of above	28,124	27,364	25,807	29,040	28,124	28,124	28,124	27,736

General notes:
Compliance strategies not shown in this table include allowance purchases, existing plant retrofits and fuel switching.
The Replacement Plant catagory includes existing units which have been replaced or repowered.
CoCo designates a co-feed (coal and gas), co-production (power and liquid products) plant technology.

Table 2
Power Market Potential For IGCC In The Northeast U. S. (Advanced IGCC)

Gas Price Escalation, %/yr	0.54%				1.50%			
Carbon Tax, $/Tonne C	$0	$25	$50	$100	$0	$25	$50	$100
Number of Plants								
Replacement Plants-IGCC	0	0	0	0	1	3	3	0
New Capacity-IGCC	19	3	0	0	63	35	4	0
Replacement Plants-Other Coal (inc CoCo)	0	0	0	0	0	0	0	0
New Capacity-Other Coal (inc CoCo)	0	0	0	0	0	0	0	0
Replacement Plants-Gas	4	12	38	96	1	5	22	73
New Capacity-Gas	41	49	33	13	0	22	38	12
Total of above	64	64	71	109	65	65	67	85
Dispatchable Capacity, MW net								
Replacement Plants-IGCC	0	0	0	0	350	1,051	1,051	0
New Capacity-IGCC	6,657	1,051	0	0	22,072	12,262	1,401	0
Replacement Plants-Other Coal (inc CoCo)	0	0	0	0	0	0	0	0
New Capacity-Other Coal (inc CoCo)	0	0	0	0	0	0	0	0
Replacement Plants-Gas	1,470	4,409	13,960	35,268	367	1,837	8,082	26,818
New Capacity-Gas	15,062	18,001	12,123	4,776	0	8,082	13,960	4,409
Total of above	23,189	23,461	26,084	40,044	22,790	23,233	24,495	31,227
Installed Capacity, MW gross								
Replacement Plants-IGCC	0	0	0	0	411	1,234	1,234	0
New Capacity-IGCC	7,813	1,234	0	0	25,906	14,392	1,645	0
Replacement Plants-Other Coal (inc CoCo)	0	0	0	0	0	0	0	0
New Capacity-Other Coal (inc CoCo)	0	0	0	0	0	0	0	0
Replacement Plants-Gas	1,613	4,840	15,327	38,720	403	2,017	8,873	29,444
New Capacity-Gas	16,537	19,764	13,310	5,243	0	8,873	15,327	4,840
Total of above	25,963	25,837	28,637	43,964	26,721	26,516	27,079	34,284
Gas Price Escalation, %/yr	3.00%				4.50%			
Carbon Tax, $/Tonne C	$0	$25	$50	$100	$0	$25	$50	$100
Number of Plants								
Replacement Plants-IGCC	2	7	11	8	2	7	13	33
New Capacity-IGCC	63	59	53	17	63	59	54	38
Replacement Plants-Other Coal (inc CoCo)	0	0	0	0	0	0	0	0
New Capacity-Other Coal (inc CoCo)	0	0	0	0	0	0	0	0
Replacement Plants-Gas	0	0	2	37	0	0	0	0
New Capacity-Gas	0	0	0	11	0	0	0	0
Total of above	65	66	66	73	65	66	67	71
Dispatchable Capacity, MW net								
Replacement Plants-IGCC	701	2,452	3,854	2,750	701	2,452	4,555	11,482
New Capacity-IGCC	22,072	20,671	18,569	5,956	22,072	20,671	18,919	13,313
Replacement Plants-Other Coal (inc CoCo)	0	0	0	0	0	0	0	0
New Capacity-Other Coal (inc CoCo)	0	0	0	0	0	0	0	0
Replacement Plants-Gas	0	0	735	13,593	0	0	0	0
New Capacity-Gas	0	0	0	4,041	0	0	0	0
Total of above	22,773	23,123	23,157	26,340	22,773	23,123	23,474	24,795
Installed Capacity, MW gross								
Replacement Plants-IGCC	822	2,878	4,523	3,229	822	2,878	5,346	13,479
New Capacity-IGCC	25,906	24,261	21,794	6,991	25,906	24,261	22,205	15,626
Replacement Plants-Other Coal (inc CoCo)	0	0	0	0	0	0	0	0
New Capacity-Other Coal (inc CoCo)	0	0	0	0	0	0	0	0
Replacement Plants-Gas	0	0	807	14,923	0	0	0	0
New Capacity-Gas	0	0	0	4,437	0	0	0	0
Total of above	26,729	27,140	27,124	29,580	26,729	27,140	27,551	29,105

General notes:
Compliance strategies not shown in this table include allowance purchases, existing plant retrofits and fuel switching.
The Replacement Plant catagory includes existing units which have been replaced or repowered.
CoCo designates a co-feed (coal and gas), co-production (power and liquid products) plant technology.

TABLE A1: Year 2010 Fossil Power Generation Forecast-Current IGCC Development Breakdown by Number of Plants

IGCC Development Level	Current				Current			
Carbon Tax	No Carbon Tax				$25/ Tonne Carbon Tax			
Gas Price Escalation, %/yr	0.54%	1.50%	3.00%	4.50%	0.54%	1.50%	3.00%	4.50%
RESULTS								
Total Demand, MW	43,229	43,229	43,229	43,229	43,229	43,229	43,229	43,229
Total Existing Site Capacity, MW	22,114	21,121	20,785	20,785	24,730	23,445	21,475	21,095
Total New Capacity Required, MW	21,143	22,136	22,472	22,472	18,527	19,812	21,782	22,162
Total New Capacity Installed, MW	22,043	22,655	22,865	22,865	19,104	20,573	22,617	22,538
Overall Compliance Strategies								
As-Is, Buy Allowances	60	63	64	64	54	57	63	64
Retrofit Existing Plant	46	46	46	46	44	45	45	45
Fuel Switch	0	0	0	0	0	0	0	0
Retirements	4	1	0	0	12	8	2	1
Replacement With New Gas	4	1	0	0	12	8	2	0
Replacement With New Coal	0	0	0	0	0	0	0	1
Repower	0	0	0	0	0	0	0	0
Additional Capacity-Gas	60	59	0	0	52	56	26	0
Additional Capacity-Coal	0	3	70	70	0	0	40	69
Total Plants	170	172	180	180	162	166	176	179
Replacement Plant Technologies-Specific								
FA NGCC	0	0	0	0	0	0	0	0
G NGCC	0	0	0	0	0	0	0	0
H NGCC	4	1	0	0	12	8	2	0
Subcritical PC	0	0	0	0	0	0	0	0
Supercritical PC	0	0	0	0	0	0	0	0
Ultrasupercritical PC	0	0	0	0	0	0	0	0
Advanced Ultrasupercritical PC	0	0	0	0	0	0	0	0
Current IGCC	0	0	0	0	0	0	0	0
Intermediate IGCC	0	0	0	0	0	0	0	0
Advanced IGCC	0	0	0	0	0	0	0	0
BPFBC	0	0	0	0	0	0	0	0
Advanced PFBC	0	0	0	0	0	0	0	1
CoCo - High Coal Option	0	0	0	0	0	0	0	0
CoCo - High Gas Option	0	0	0	0	0	0	0	0
Replacement Plant Technologies-Summary								
NGCC	4	1	0	0	12	8	2	0
PC	0	0	0	0	0	0	0	0
IGCC	0	0	0	0	0	0	0	0
PFBC	0	0	0	0	0	0	0	1
CoCo	0	0	0	0	0	0	0	0
Total Plants	4	1	0	0	12	8	2	1
Retrofit Technologies								
Year Round Nat. Gas Fuel Switch	0	0	0	0	0	0	0	0
Seasonal Nat. Gas Fuel Switch	0	0	0	0	0	0	0	0
FGD	6	6	6	6	4	4	4	4
LNB	28	28	28	28	27	28	28	28
LNB/OFA	7	7	7	7	7	7	7	7
SNCR	9	9	9	9	9	9	9	9
SCR	0	0	0	0	0	0	0	0
Repower Technologies								
G NGCC	0	0	0	0	0	0	0	0
Advanced IGCC	0	0	0	0	0	0	0	0
Advanced PFBC	0	0	0	0	0	0	0	0
Additional Capacity Technologies-Specific								
FA NGCC	0	0	0	0	0	0	0	0
G NGCC	0	0	0	0	0	0	0	0
H NGCC	60	59	0	0	52	56	26	0
Subcritical PC	0	0	0	0	0	0	0	0
Supercritical PC	0	0	0	0	0	0	0	0
Ultrasupercritical PC	0	0	0	0	0	0	0	0
Advanced Ultrasupercritical PC	0	0	0	0	0	0	0	0
Current IGCC	0	0	0	0	0	0	0	0
Intermediate IGCC	0	0	0	0	0	0	0	0
Advanced IGCC	0	0	0	0	0	0	0	0
BPFBC	0	0	0	0	0	0	0	0
Advanced PFBC	0	3	70	70	0	0	40	69
CoCo - High Coal Option	0	0	0	0	0	0	0	0
CoCo - High Gas Option	0	0	0	0	0	0	0	0
Additional Power Technologies-Summary								
NGCC	60	59	0	0	52	56	26	0
PC	0	0	0	0	0	0	0	0
IGCC	0	0	0	0	0	0	0	0
PFBC	0	3	70	70	0	0	40	69
CoCo	0	0	0	0	0	0	0	0
Total Plants	60	62	70	70	52	56	66	69

TABLE A1 (cont)
YEAR 2010 FOSSIL POWER GENERATION FORECAST-CURRENT IGCC DEVELOPMENT: Breakdown By Number of Plants

IGCC Development Level	Current				Current			
Carbon Tax	$50/ Tonne Carbon Tax				$100/ Tonne Carbon Tax			
Gas Price Escalation, %/yr	0.54%	1.50%	3.00%	4.50%	0.54%	1.50%	3.00%	4.50%
RESULTS								
Total Demand, MW	43,229	43,229	43,229	43,229	43,229	43,229	43,229	43,229
Total Existing Site Capacity, MW	31,912	28,591	23,474	22,559	39,124	38,954	33,866	26,177
Total New Capacity Required, MW	11,335	14,657	19,783	20,698	4,106	4,276	9,382	17,079
Total New Capacity Installed, MW	12,123	15,062	20,410	20,905	4,776	4,409	9,919	17,759
Overall Compliance Strategies								
As-Is, Buy Allowances	44	49	60	62	7	17	39	56
Retrofit Existing Plant	28	36	42	42	0	12	25	36
Fuel Switch	0	0	0	0	0	0	0	0
Retirements	38	25	8	6	103	81	46	17
Replacement With New Gas	38	25	8	0	96	73	45	10
Replacement With New Coal	0	0	0	6	0	0	0	7
Repower	0	0	0	0	0	0	0	1
Additional Capacity-Gas	33	41	52	0	13	12	27	27
Additional Capacity-Coal	0	0	4	64	0	0	0	24
Total Plants	143	151	166	174	116	114	136	161
Replacement Plant Technologies-Specific								
FA NGCC	0	0	0	0	0	0	0	0
G NGCC	0	0	0	0	0	0	0	0
H NGCC	38	25	8	0	96	73	45	10
Subcritical PC	0	0	0	0	0	0	0	0
Supercritical PC	0	0	0	0	0	0	0	0
Ultrasupercritical PC	0	0	0	0	0	0	0	0
Advanced Ultrasupercritical PC	0	0	0	0	0	0	0	0
Current IGCC	0	0	0	0	0	0	0	0
Intermediate IGCC	0	0	0	0	0	0	0	0
Advanced IGCC								
BPFBC	0	0	0	0	0	0	0	0
Advanced PFBC	0	0	0	6	0	0	0	7
CoCo - High Coal Option	0	0	0	0	0	0	0	0
CoCo - High Gas Option	0	0	0	0	0	0	0	0
Replacement Plant Technologies-Summary								
NGCC	38	25	8	0	96	73	45	10
PC	0	0	0	0	0	0	0	0
IGCC	0	0	0	0	0	0	0	0
PFBC	0	0	0	6	0	0	0	7
CoCo	0	0	0	0	0	0	0	0
Total Plants	38	25	8	6	96	73	45	17
Retrofit Technologies								
Year Round Nat. Gas Fuel Switch	0	0	0	0	0	0	0	0
Seasonal Nat. Gas Fuel Switch	0	0	0	0	0	0	0	0
FGD	1	1	1	1	0	0	0	0
LNB	18	23	28	28	0	5	16	24
LNB/OFA	6	6	7	7	0	6	6	6
SNCR	5	8	9	9	0	3	5	8
SCR	0	0	0	0	0	0	0	0
Repower Technologies								
G NGCC	0	0	0	0	0	0	0	0
Advanced IGCC								
Advanced PFBC	0	0	0	0	0	0	0	1
Additional Capacity Technologies-Specific								
FA NGCC	0	0	0	0	0	0	0	0
G NGCC	0	0	0	0	0	0	0	0
H NGCC	33	41	52	0	13	12	27	27
Subcritical PC	0	0	0	0	0	0	0	0
Supercritical PC	0	0	0	0	0	0	0	0
Ultrasupercritical PC	0	0	0	0	0	0	0	0
Advanced Ultrasupercritical PC	0	0	0	0	0	0	0	0
Current IGCC	0	0	0	0	0	0	0	0
Intermediate IGCC	0	0	0	0	0	0	0	0
Advanced IGCC								
BPFBC	0	0	0	0	0	0	0	0
Advanced PFBC	0	0	4	64	0	0	0	24
CoCo - High Coal Option	0	0	0	0	0	0	0	0
CoCo - High Gas Option	0	0	0	0	0	0	0	0
Additional Power Technologies-Summary								
NGCC	33	41	52	0	13	12	27	27
PC	0	0	0	0	0	0	0	0
IGCC	0	0	0	0	0	0	0	0
PFBC	0	0	4	64	0	0	0	24
CoCo	0	0	0	0	0	0	0	0
Total Plants	33	41	56	64	13	12	27	51

TABLE A2
YEAR 2010 FOSSIL POWER GENERATION FORECAST-ADVANCED IGCC
Breakdown By Number of Plants

IGCC Development Level	Fully-Developed				Fully-Developed			
Carbon Tax	No Carbon Tax				$25/ Tonne Carbon Tax			
Gas Price Escalation, %/yr	0.54%	1.50%	3.00%	4.50%	0.54%	1.50%	3.00%	4.50%
RESULTS								
Total Demand, MW	43,229	43,229	43,229	43,229	43,229	43,229	43,229	43,229
Total Existing Site Capacity, MW	22,114	21,408	21,391	21,391	24,730	23,394	23,005	23,005
Total New Capacity Required, MW	21,143	21,848	21,865	21,865	18,527	19,863	20,252	20,252
Total New Capacity Installed, MW	21,719	22,072	22,072	22,072	19,052	20,345	20,671	20,671
Overall Compliance Strategies								
As-Is, Buy Allowances	60	62	62	62	54	57	58	58
Retrofit Existing Plant	46	46	46	46	44	45	45	45
Fuel Switch	0	0	0	0	0	0	0	0
Retirements	4	2	2	2	12	8	7	7
Replacement With New Gas	4	1	0	0	12	5	0	0
Replacement With New Coal	0	1	2	2	0	3	7	7
Repower	0	0	0	0	0	0	0	0
Additional Capacity-Gas	41	0	0	0	49	22	0	0
Additional Capacity-Coal	19	63	63	63	3	35	59	59
Total Plants	170	173	173	173	162	167	169	169
Replacement Plant Technologies-Specific								
FA NGCC	0	0	0	0	0	0	0	0
G NGCC	0	0	0	0	0	0	0	0
H NGCC	4	1	0	0	12	5	0	0
Subcritical PC	0	0	0	0	0	0	0	0
Supercritical PC	0	0	0	0	0	0	0	0
Ultrasupercritical PC	0	0	0	0	0	0	0	0
Advanced Ultrasupercritical PC	0	0	0	0	0	0	0	0
Current IGCC	0	0	0	0	0	0	0	0
Intermediate IGCC	0	0	0	0	0	0	0	0
Advanced IGCC	0	1	2	2	0	3	7	7
BPFBC	0	0	0	0	0	0	0	0
Advanced PFBC	0	0	0	0	0	0	0	0
CoCo - High Coal Option	0	0	0	0	0	0	0	0
CoCo - High Gas Option	0	0	0	0	0	0	0	0
Replacement Plant Technologies-Summary								
NGCC	4	1	0	0	12	5	0	0
PC	0	0	0	0	0	0	0	0
IGCC	0	1	2	2	0	3	7	7
PFBC	0	0	0	0	0	0	0	0
CoCo	0	0	0	0	0	0	0	0
Total Plants	4	2	2	2	12	8	7	7
Retrofit Technologies								
Year Round Nat. Gas Fuel Switch	0	0	0	0	0	0	0	0
Seasonal Nat. Gas Fuel Switch	0	0	0	0	0	0	0	0
FGD	6	6	6	6	4	4	4	4
LNB	28	28	28	28	27	28	28	28
LNB/OFA	7	7	7	7	7	7	7	7
SNCR	9	9	9	9	9	9	9	9
SCR	0	0	0	0	0	0	0	0
Repower Technologies								
G NGCC	0	0	0	0	0	0	0	0
Advanced IGCC	0	0	0	0	0	0	0	0
Advanced PFBC	0	0	0	0	0	0	0	0
Additional Capacity Technologies-Specific								
FA NGCC	0	0	0	0	0	0	0	0
G NGCC	0	0	0	0	0	0	0	0
H NGCC	41	0	0	0	49	22	0	0
Subcritical PC	0	0	0	0	0	0	0	0
Supercritical PC	0	0	0	0	0	0	0	0
Ultrasupercritical PC	0	0	0	0	0	0	0	0
Advanced Ultrasupercritical PC	0	0	0	0	0	0	0	0
Current IGCC	0	0	0	0	0	0	0	0
Intermediate IGCC	0	0	0	0	0	0	0	0
Advanced IGCC	19	63	63	63	3	35	59	59
BPFBC	0	0	0	0	0	0	0	0
Advanced PFBC	0	0	0	0	0	0	0	0
CoCo - High Coal Option	0	0	0	0	0	0	0	0
CoCo - High Gas Option	0	0	0	0	0	0	0	0
Additional Power Technologies-Summary								
NGCC	41	0	0	0	49	22	0	0
PC	0	0	0	0	0	0	0	0
IGCC	19	63	63	63	3	35	59	59
PFBC	0	0	0	0	0	0	0	0
CoCo	0	0	0	0	0	0	0	0
Total Plants	60	63	63	63	52	57	59	59

TABLE A2 (cont)
YEAR 2010 FOSSIL POWER GENERATION FORECAST-ADVANCED IGCC
Breakdown By Number of Plants

IGCC Development Level	Fully-Developed				Fully-Developed			
Carbon Tax	$50/ Tonne Carbon Tax				$100/ Tonne Carbon Tax			
Gas Price Escalation, %/yr	0.54%	1.50%	3.00%	4.50%	0.54%	1.50%	3.00%	4.50%
RESULTS								
Total Demand, MW	43,229	43,229	43,229	43,229	43,229	43,229	43,229	43,229
Total Existing Site Capacity, MW	31,912	28,540	24,863	24,829	39,124	38,954	33,677	30,130
Total New Capacity Required, MW	11,335	14,708	18,394	18,428	4,106	4,276	9,571	13,127
Total New Capacity Installed, MW	12,123	15,362	18,569	18,919	4,776	4,409	9,997	13,313
Overall Compliance Strategies								
As-Is, Buy Allowances	44	49	58	58	7	17	39	47
Retrofit Existing Plant	28	36	39	39	0	12	25	30
Fuel Switch	0	0	0	0	0	0	0	0
Retirements	38	25	13	13	103	81	44	30
Replacement With New Gas	38	22	2	0	96	73	37	0
Replacement With New Coal	0	3	11	13	0	0	6	30
Repower	0	0	0	0	0	0	2	3
Additional Capacity-Gas	33	38	0	0	13	12	11	0
Additional Capacity-Coal	0	4	53	54	0	0	17	38
Total Plants	143	152	163	164	116	114	137	148
Replacement Plant Technologies-Specific								
FA NGCC	0	0	0	0	0	0	0	0
G NGCC	0	0	0	0	0	0	0	0
H NGCC	38	22	2	0	96	73	37	0
Subcritical PC	0	0	0	0	0	0	0	0
Supercritical PC	0	0	0	0	0	0	0	0
Ultrasupercritical PC	0	0	0	0	0	0	0	0
Advanced Ultrasupercritical PC	0	0	0	0	0	0	0	0
Current IGCC	0	0	0	0	0	0	0	0
Intermediate IGCC	0	0	0	0	0	0	0	0
Advanced IGCC	0	3	11	13	0	0	6	30
BPFBC	0	0	0	0	0	0	0	0
Advanced PFBC	0	0	0	0	0	0	0	0
CoCo - High Coal Option	0	0	0	0	0	0	0	0
CoCo - High Gas Option	0	0	0	0	0	0	0	0
Replacement Plant Technologies-Summary								
NGCC	38	22	2	0	96	73	37	0
PC	0	0	0	0	0	0	0	0
IGCC	0	3	11	13	0	0	6	30
PFBC	0	0	0	0	0	0	0	0
CoCo	0	0	0	0	0	0	0	0
Total Plants	38	25	13	13	96	73	43	30
Retrofit Technologies								
Year Round Nat. Gas Fuel Switch	0	0	0	0	0	0	0	0
Seasonal Nat. Gas Fuel Switch	0	0	0	0	0	0	0	0
FGD	1	1	1	1	0	0	0	0
LNB	18	23	25	25	0	5	16	20
LNB/OFA	6	6	7	7	0	6	6	6
SNCR	5	8	9	9	0	3	5	6
SCR	0	0	0	0	0	0	0	0
Repower Technologies								
G NGCC	0	0	0	0	0	0	0	0
Advanced IGCC	0	0	0	0	0	0	2	3
Advanced PFBC	0	0	0	0	0	0	0	0
Additional Capacity Technologies-Specific								
FA NGCC	0	0	0	0	0	0	0	0
G NGCC	0	0	0	0	0	0	0	0
H NGCC	33	38	0	0	13	12	11	0
Subcritical PC	0	0	0	0	0	0	0	0
Supercritical PC	0	0	0	0	0	0	0	0
Ultrasupercritical PC	0	0	0	0	0	0	0	0
Advanced Ultrasupercritical PC	0	0	0	0	0	0	0	0
Current IGCC	0	0	0	0	0	0	0	0
Intermediate IGCC	0	0	0	0	0	0	0	0
Advanced IGCC	0	4	53	54	0	0	17	38
BPFBC	0	0	0	0	0	0	0	0
Advanced PFBC	0	0	0	0	0	0	0	0
CoCo - High Coal Option	0	0	0	0	0	0	0	0
CoCo - High Gas Option	0	0	0	0	0	0	0	0
Additional Power Technologies-Summary								
NGCC	33	38	0	0	13	12	11	0
PC	0	0	0	0	0	0	0	0
IGCC	0	4	53	54	0	0	17	38
PFBC	0	0	0	0	0	0	0	0
CoCo	0	0	0	0	0	0	0	0
Total Plants	33	42	53	54	13	12	28	38